Title: System dynamics within typical days of a high variable 2030 European power system

Keywords: Power system modelling; European power system; Variable renewables; Integrated energy market; Artelys Crystal Super Grid

Authors:

Brinkerink, Maarten [a,b,*]

Shivakumar, Abhishek [a]

[a]: KTH Royal Institute of Technology, Department of Energy Technology, Division of Energy Systems Analysis, Brinellvägen 68, 100 44 Stockholm, Sweden

[b]: University College Cork (UCC), Environmental Research Institute (ERI), Centre for Marine and Renewable Energy (MaREI), 6 Lee Road, T23 E4PW Cork, Ireland

*: Corresponding author: maarten.brinkerink@ucc.ie

+353214901956

Abstract: The effect of variability in electricity generation on future high variable European power systems is a subject of extensive research within the current scientific literature. The common approach in these studies, regarding the assessment of the impact of the variability and related balancing assets, is by showing yearly aggregates (or longer) of results based on a variety of indicators. Although significant, these studies often lack in temporal details. This paper therefore focuses on the dynamics between load, generation, marginal cost and assets for balancing the generation variability, within a variety of typical days in a fully-integrated European power market. This is done by assessments of daily snapshots based on an hourly time resolution. The assessments underline the necessity of balancing assets, both during peaks as well as during lows in the output of variable generators. Interconnection capacity, electricity storage and demand response (DR) applications all contribute to renewables integration and to optimized utilization of cost-efficient generation capacity throughout the European power system. Important load flows from and towards load centers with high capacities of variable renewables are identified, as well as a significant role for transit countries with high interconnection capacities between these load centers. Despite the importance of electricity storage, it is shown that the traditional diurnal utilization of centralized electricity storage fleets becomes less viable with increasing penetration of variable renewables. A potential high CO2 price in the future European power market can become a determining factor in the system dynamics. Large price differentials in the merit order stimulate long distance flows as well as an increasing profitability for storage assets.

1. Introduction

In response to a changing climate and concerns regarding the availability of sufficient fossil fuel reserves [1], the member states of the European Union (EU) have set binding targets of respectively 20% [2] and 27% [3] of final energy consumption from renewables by 2020 and 2030 at the EU level. With a relative share of 21.9% of electricity in the final energy consumption of the EU in 2013 and considering an expected growth of electricity in the final energy consumption [4,5], a significant proportion of these targets must be achieved within the electricity sector. The growth potential of hydro power as current most mature renewable electricity source (RES-E) is fairly limited since the best locations are already in use [6]. RES-E with larger room of growth are solar photovoltaics (PV) and wind power. This is supported by impressive historical growth rates of on average 41% per year for solar-PV since 2000 and a growth rate of 15% in 2015 of worldwide installed wind capacity [7,8], as well as by realistic estimates for the potential of further increment of generation capacity [9,10].

An important characteristic of both wind power and solar-PV is that the generation of electricity occurs variably depending on the magnitude of solar radiation and wind intensity. At lower penetration levels of variable renewables (VRES), this variation can be compensated by dispatch of thermal power plants to secure the stability on the grid [11]. At higher penetration levels this becomes more difficult due to the non-dispatchable nature of VRES as well as the often-limited flexibility of thermal power plants [12]. To facilitate the integration of high capacities of VRES in power systems, a wide variety of methods for balancing the generation are being studied and applied. Examples are the improved flexibility of thermal power plants [13], better forecasting techniques for demand and generation [11,14], smart geographical placement of VRES [15], a variety of technologies for the storage of electricity [13,16], application of demand response (DR) assets [14,17-19] and increased interconnection capacities [20,21].

In the European context, a crucial step regarding the growing penetration of VRES would be the completion of a fully-integrated internal European energy market where electricity can flow freely between all countries [2]. The free flow of electricity would stimulate cost-efficient electricity generation by using generation technologies with the lowest marginal cost across Europe. Secondly, due to the generally low marginal cost of solar-PV and wind power, the growth potential for these systems would become even higher in an integrated market. Although in the past the progress towards the integrated market has been delayed [22], significant developments have been accomplished such as the coupling of the day-ahead market and the increase of HVDC interconnection capacity [23].

2. Literature review

Considering the expected development of the European power system in the direction of a more variable nature of generation, a range of studies have been conducted regarding the implications on the European scale and on the impact of possible methods for treating the variability within these high variable European power systems.

The biennially released 10-year network development plan (TYNDP) of the European Network of Transmission System Operators for Electricity (ENTSO-E) [24,25] showcases the necessity of on average a doubling in interconnection capacity by 2030, to facilitate the growing integration of VRES and to optimally utilize the available generation capacity within the European power system. A range of projected development visions are simulated in a variety of market modelling tools, including PowerSYM [26]. The impact of the different visions, including deviating assumptions on balancing assets and power market integration, are assessed through a variety of indicators such as national generation profiles, CO2 emissions, power exchange and differences in marginal cost. Results are separated per country, yet aggregated per year. The ENTSO-E TYNDP projections are expected to inform policy development and decision-making in the EU, at both the European Commission (EC) and in individual Member States.

The 2030 power perspectives study is constructed as an intermediate step towards the EU energy roadmap 2050 [27]. It provides a view on the progress needed by 2030 to be able to achieve the goals set in the EU energy roadmap 2050. It includes a technical assessment of the EU power grid and the impact of certain key elements such as DR, sharing of spinning reserves and incremental transmission capacities. Simulations of the European power system are conducted in the PRIMES model [28] with yearly aggregated output of results. The study highlights the importance of a diverse and compatible portfolio of low-carbon generation technologies across Europe and confirms the necessity of investments in interconnection capacity. Demand-side resources such as demand response assets and energy efficiency are indicated as an attractive mean to reduce the required investments in large-scale generation and interconnection capacity.

Gils et. al. [29,30] and Scholz et. al. [30] present REMix, an energy systems model used to assess capacity expansion and hourly dispatch at various levels of solar-PV and wind power penetration. The studies assess the impact of increasing shares of VRES on the power system of Europe, with high temporal and spatial resolution. The studies are, however, not focused on the role of cross-border interconnectors. Deane et. al. [31] present an integrated gas and electricity model of the EU energy system to examine supply interruptions. The model includes all 28 EU Member States and uses an hourly resolution. The focus of the study is the impact of interruptions in gas supply and storage on the energy system as a whole. A study by Qadrdan et. al. [32] introduces CGEN+ to assess the role of DR as a source of flexibility in the EU's power system. Other sources of flexibility, such as large-scale storage and cross-border interconnectors, are not considered in similar detail and the model is limited to the case of Great Britain.

Energynautics GmbH has performed a European grid study for 2030 and 2050 [33]. The authors used grid optimization software ENAplan [34] to perform hourly dispatch simulations and assessed multiple scenarios with varying assumptions regarding priority dispatch for RES-E, DR integration, electricity storage, flexibility of conventional power plants and interconnection capacities. The study shows the importance of priority dispatch for RES-E between zones to minimize renewable curtailment. It also shows the potential of demand response for renewables integration. Not only does it underline the significance of load shifting from peak to off-peak hours, it also indicates that a shift of load towards times of peaks in high variable generation can lower the need for interconnection capacity. French electricity company Électricité de France (EDF) has performed a technical and economic analysis of the 2030 European power system with a 60% share of generated electricity from RES-E [35]. It includes aggregated results based on hourly dispatch simulations from the Continental model [36]. The study among others assesses the role of base-load and peak-load generators in a system with a high share of VRES. Important conclusion from the study is that storage and demand response can contribute to required flexibility in balancing supply and demand, but do not replace the need for backup generation.

The effect of variability in generation and the potential impact of balancing assets in the 2030 European power system have been extensively explored and quantified in the existing literature. Yet, the general approach in the presentation of results in these studies is by showing yearly aggregates and therefore often lack in temporal details. In this paper we will break away from this common method and focus on daily snapshots for a variety of representative days. The aim is to get a better understanding of what a typical day of electricity generation and consumption by 2030 in a high variable generating environment could potentially look like. This will include an analysis of the role of three main assets for balancing the variability, being centralized electricity storage, DR applications and cross-border electricity transmission. The specific interest of this study is more on the dynamics in the relation between generation, load, balancing assets and the marginal cost of electricity generation in different situations in the European context, rather than exact quantification of factors on the long term. By focusing on the dynamics at hourly resolution, this study attempts to provide additional insights on the high RES-E visions of the ENTSO-E regarding the 2030 European power system, as put forward within their Ten-Year Network Development Plan (TYNDP) [25].

3. Methodology

3.1 *Artelys Crystal Super Grid*

To simulate the operations of the European power system with realistic decision-making functionalities, a dispatch model has been used with an hourly time resolution. This high

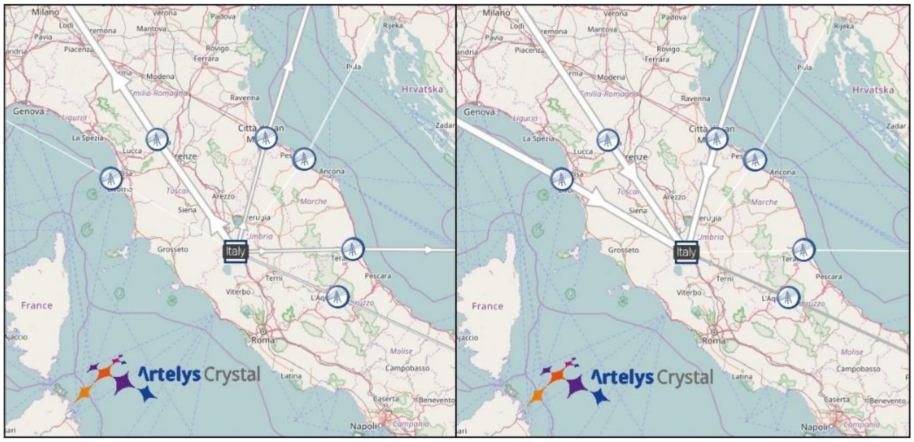

Figure 1 Visualization of electricity flows from and towards Italy in Artelys Crystal Super Grid, July 24 1PM (left) and July 25 1AM (right). Width of the arrows indicates the relative size of the flows.

resolution is required for studying the integration of RES-E and associated flexibility assets. The specific software selected for this study is Artelys Crystal Super Grid. The model performs simulations of the European power system at country level on hourly basis by optimizing the utilization of generating units, electricity storage and cross-border transmission, while considering technical constraints. The optimization occurs by securing a supply of electricity with the overall lowest costs within a user-defined sliding time horizon. Figure 1 shows an exemplary representation of hourly cross-border load flows from and to Italy during a summer day and night as visualized within the Artelys Crystal Super Grid software.

3.2 *Construction of the 2030 European power system*

The simulation of potential high variable European power systems within this study are based on the TYNDP 2016 [25], providing additional insights on the implications of the high RES-E visions within the projected range of the ENTSO-E. Per vision, the study includes country-specific installed generating capacities, interconnection capacities, hourly load patterns and other factors such as fuel and CO2 prices. Based on these elements, the model can determine the marginal cost of electricity generation per country per hour. The simulated European power system consists of the EU member states, in addition to Norway, Switzerland and the non-EU Balkan countries. Power exchange with countries outside this area occurs based on fixed contracts. For this study, Vision 3 (V3) and Vision 4 (V4) have been simulated in Artelys Crystal Super Grid. These visions have the highest installed capacities of RES-E (V3 48.18% and V4 50.2% Europe average) and more specifically highest installed capacities of VRES (V3 42.14% and V4 44.26% Europe average) by 2030 [37]. For an overview of all determining characteristics per vision and the supporting storylines refer to [38]. Installed generation and interconnection capacities for the TYNDP visions per country, as used for this study, can be found in [37]. Important consideration in V3 and V4 is that the generation of electricity from closed cycle gas turbines (CCGT) is set before the coal and lignite fleet in the merit order, due to high CO2 prices of respectively €71 and €76/ton CO2. Consequentially, this means that CCGT fleets are generally used as base load, whereas coal and lignite fleets are functioning as peak supply. This is contrary to the current market situation. It is therefore important to assess the results of this study within this context. Further implications of the incorporated high CO2 prices are discussed in section 5.

Unfortunately, not all assumptions and data in the TYNDP report are quantified or specified for each country and hence additional data sources were needed for the modelling. The Artelys Crystal Super Grid software includes a data package from which the normalized weather patterns per country for solar-PV, onshore- and offshore wind power were used as well as some basic technological information for the European grid and generation assets. The patterns used for the simulations in this study are based on data of the 2008 meteorological year. Installed capacities for wind power per country within the TYNDP study are accumulated in one category. To get a best estimate on deviated installed capacities for on- and offshore wind power, per country, the ratios in the 'high wind energy scenario' of the European Wind Energy Association (EWEA) [39] for 2030 were used as basis for countries with potential for offshore wind power. Transmission losses on interconnections have been specified per connection, based on the type (AC/HVDC) and distance of the specific transmission lines. For the wheeling charges a uniform price of €3, - per MWh of transmitted electricity has been applied, following the data of a previously conducted study by University College Cork (UCC) regarding the 2030 EU28 power system [40].

3.3 *Assessment of system dynamics in a high variable European power system*

For the purpose of this study, the 2030 European power system has been assessed as a fully-integrated market. A zonal pricing approach has been applied as described by Hogan [41]. Within this approach the electricity market can be seen as one large pool of generators and load with differentiated costs of generation per technology. The costs of generation per technology are determined by the operating cost, the emissions and the CO2 price. The marginal cost of electricity generation at each zone, being separate countries within this study, is equal to its most expensive unit of generated or consumed electricity at that zone plus one. If no transmission congestion occurs between countries, the marginal cost of electricity generation is theoretically speaking equal throughout Europe, apart from wheeling charges for the importing countries. If congestion between two zones does occur, the optimal functionality of the integrated market between these areas will be affected, resulting in a split of the costs of generation into two different local marginal prices (LMP). To analyse the dynamics of a European power system with a high integration of VRES, this paper is built on a series of daily snapshots based on the hourly output of the simulations in Artelys Crystal Super Grid. It starts with a variety of cases in different situations to indicate the necessity of integration of assets for balancing the variability in generation. This is followed by separate assessments of the functionality and potential roles of three main assets for balancing the variability in generation, being centralized Pumped Hydroelectric Storage (PHS), cross-border electricity transmission and DR applications. Assessments of the European power system are conducted for representative (average) days and for more extremes as well, being low variable generation or high variable generation in different seasons to give a comprehensive overview of a variety of possible situations in 2030. For the assessment of electricity storage and cross-border transmission the simulations of V3 have been used, in which both assets are simulated as active components within the power market.

The functionality of DR applications, for example the use of flexible charging and generation of electric vehicles or the flexible use of domestic heat pumps, are assessed through simulations of V4. The difference with the other assessments is that DR has not been integrated as an active component within the simulations. This is because of the way the load profiles of the TYNDP are constructed, where the potential impact of DR applications is predetermined on the load profiles [24]. To be able to assess the impact of DR on the daily dynamics in the system, it is necessary to develop a reference case for V4 without influence of DR. Adapting a load profile is a delicate task and cannot be applied in the same manner for every day due to differences in the diurnal cycle between different periods of the year. Furthermore, although it has been mentioned in the TYNDP report that there are differences in assumed DR capacities for different European countries, it has not been quantified. This means that there is no single uniform approach to correctly alter the load profiles of all countries. The choice has therefore been made to adapt the V4 load profiles for a few exemplary days. This has been done by taking the load profile of comparable days of V4 without integrated DR effect as reference. Based on the reference data, the shape of the profiles of the exemplary days have been adapted and proportionally scaled. The total demand for the changed days in the adapted profile has remained exactly equal. An example of an original and adapted load profile can be seen in figure 2. Following [38], within vision 4 of the TYNDP 2016 it has been assumed that 20% of the total European load can be shifted by a variety of DR assets from expected high prices to expected low prices.

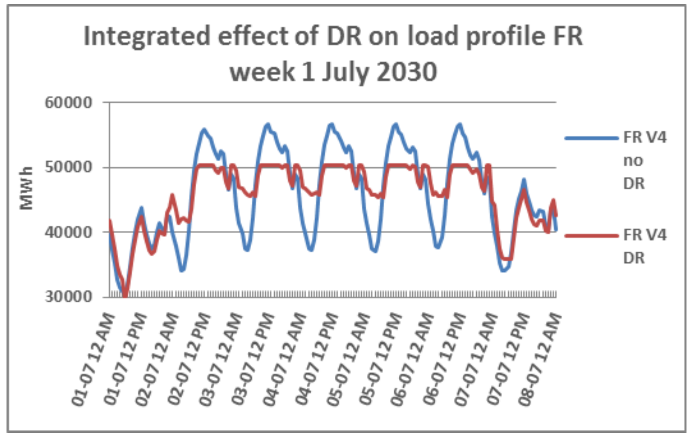

Figure 2 Exemplary load profiles with and without integrated effect of DR**.**

This includes load shedding as well as load shifting to periods before and after the initial timeframe of demand in different sectors. Furthermore, 10% of the European load can be influenced by smart charging and generation of Electric Vehicles (EV) and 9% of the European load can be shifted using heat pumps.

4. Results

4.1 *The necessity of assets for balancing variability in electricity generation*

In this section, we include a variety of daily snapshots based on simulations of V3 of the TYNDP 2016, to underline the necessity of assets for balancing the variability in electricity generation. The top side of figure 3 shows two contrasting days of electricity generation and consumption in Italy. Approximately 27% of Italy's installed capacity in the simulated 2030 power system is based on solar-PV, corresponding to 40.4 GW. Second specific characteristic of the Italian system is that it has relatively low capacity for fulfilling its system adequacy in a cost-efficient manner. Nuclear energy for example is not part of the power system in Italy. These elements combined creates a situation where during days of low variable generation, especially during winter days for example on February 12 as shown in the graph, Italy relies on its full available capacity of 'must run' power plants, combined cycle gas fleet (CCGT), coal power plants and hydro fleet. Yet this combined generation is not sufficient to fulfil the demand entirely. To prevent further increase of the marginal cost, by generating electricity from open cycle gas turbines (OCGT) or even from fuel oil power stations, Italy is dependent on alternatives for fulfilling its demand during periods of lower variable generation.

Due to the large installed capacity of solar-PV and the Mediterranean climate in Italy, there's a recurring peak in variable electricity generation during daytime. Especially during days of lower demand, for example in weekends or in the case of May 1 during a national holiday as shown on the right side of Figure 3, this can lead to a large oversupply of electricity, totaling 102.4 GWh on this specific day with an hourly maximum of 15.8 GW. Although quantity wise this example is

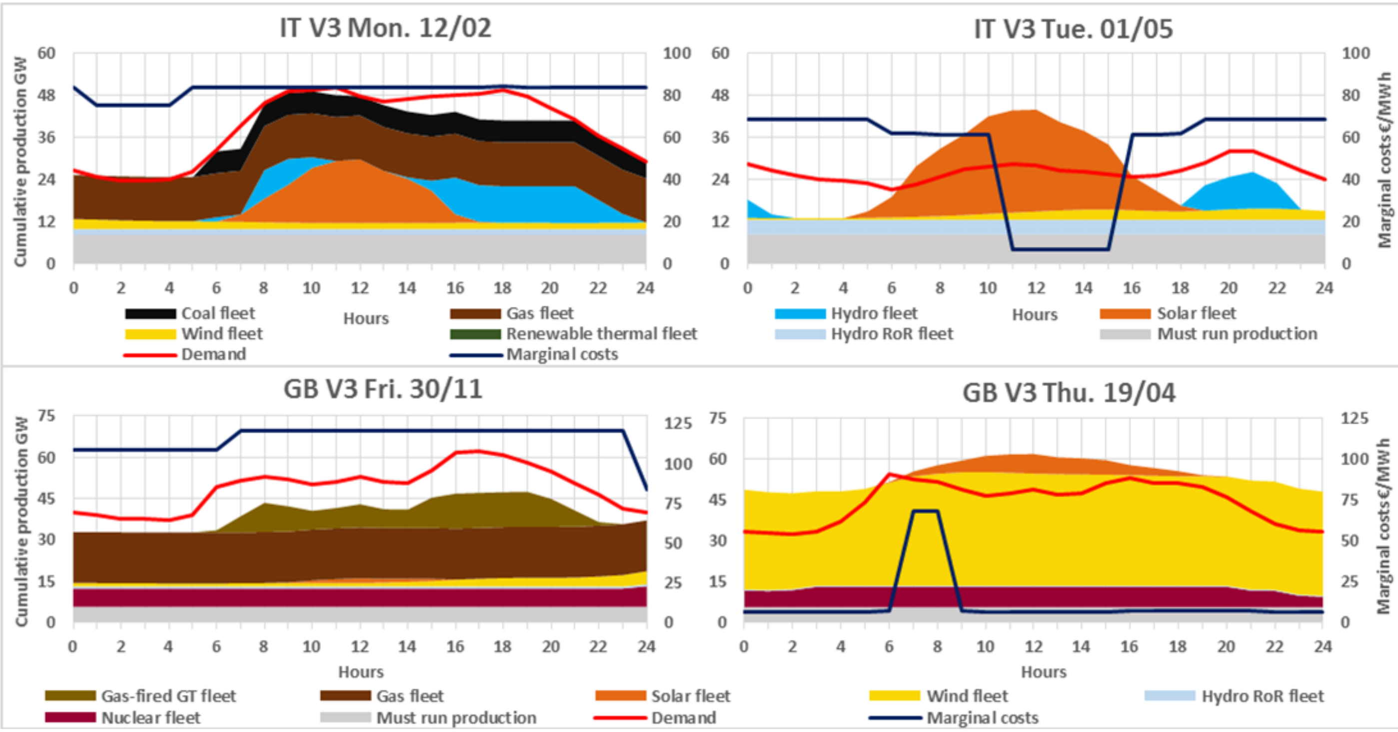

Figure 3 2030 electricity generation and consumption in Italy (IT), February 12 (Top left) and May 1 (Top right), and Great Britain (GB), November 30 (Bottom left) and April 19 (Bottom right) to showcase the necessity of assets for balancing variability in electricity generation.

rather extreme, it is not an incidental occurrence. In the case of Italy, oversupply occurs during almost 900 hours within the simulated year. The vast majority of these hours of oversupply occur in spring (363) and summer (301), compared to approximately 100 hours in both fall and winter. The maximum oversupply occurs at 17 GW in spring compared to a maximum in winter of just above 10 GW. Oversupply peaks in spring due to a combination of relatively low consumer demand and strong influence of variable generation. To stimulate RES-E integration and to prevent electricity curtailment, alternatives for the use of this surplus electricity must be adopted.

The bottom side of figure 3 includes two daily snapshots of electricity generation and consumption within Great Britain (GB). GB has an above average installed capacity of VRES around approximately 55%. Next to this, where Italy is dominated by solar-PV, GB relies mainly on the generation of electricity from wind turbines. November 30 is a day with extremely low variable generation due to a period of absence of wind. The demand during this particular day is relatively high compared to the yearly average. Throughout a significant part of the day the full capacity of GB's non-variable generation fleet is in use, raising the marginal cost to 121 €/MWh. To prevent loss of load (LOL) on the electricity grid, GB is dependent on alternative assets to balance these lows in variable generation.

During the 19th of April, there's a continuous high supply of electricity from wind turbines, averaging between 67% and 81% of full installed capacity. This, combined with GB's limited flexible baseload generation, results in a consistent oversupply of electricity throughout the day. This is a different situation compared to Italy's case where the oversupply of electricity is more temporally concentrated around midday due to the higher influence of solar-PV generated electricity. The occurrence of oversupply in GB is far more common compared to Italy with more than 3400 hours throughout the year. This can mainly be assigned to the significant and consistent influence of generated electricity from GB's wind fleet. Interseasonally, oversupply ranges between 919 hours in fall and 805 hours in spring. Maximum oversupply ranges between almost 16 GW in summer and 17 GW in winter. This consistent oversupply in GB also demands additional assets for preventing unwanted curtailment of electricity, yet likely in a different setup compared to Italy's case due to the more spread out nature of oversupply.

To recap, there are multiple reasons why assets for balancing variability should be integrated in a high variable European power system. For example, to prevent the utilization of expensive backup generation for fulfilling the system adequacy, to manage peak- or consistent oversupply, or to prevent loss of load on the electricity grid.

4.2 *Centralized electricity storage (PHS)*

To assess the functionality of PHS in a high variable context, we will start with a stand-alone case where the storage facilities are used for domestic purposes. PHS in a cross-border context will be treated in section 4.3.3. Figure 4 shows two days of electricity generation and consumption in Spain, zooming in on the functionality of PHS in two different situations. On April 23rd, there's a high temporal peak production of VRES during daytime, resulting in a total peak supply of approximately 57 GW. This peak results in an oversupply of maximum 17 GW and 110 GWh in total. The marginal cost during this oversupply decreases significantly, making it attractive for storage facilities

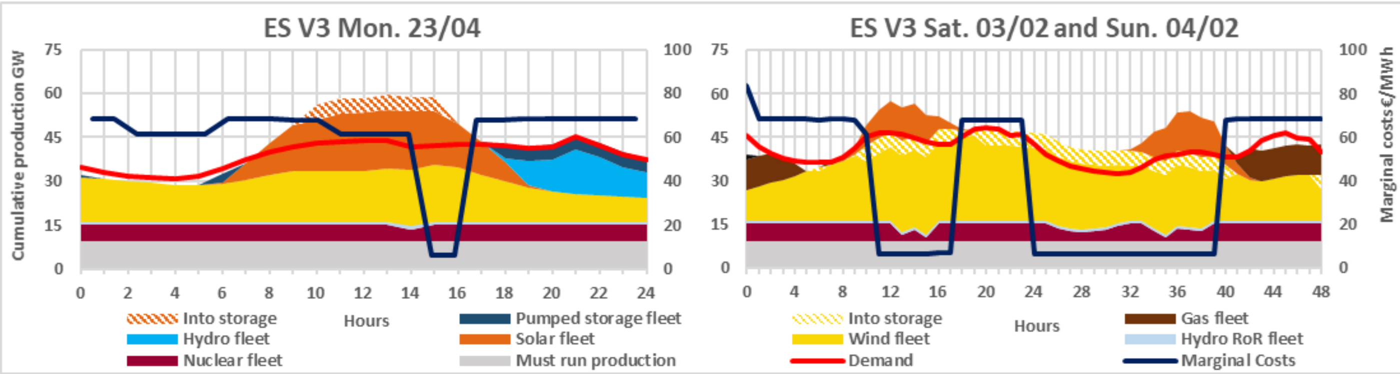

Figure 4 2030 electricity generation and consumption in Spain (ES), April 23 (left) and February 3 and 4 (right) to indicate the functionality of centralized electricity storage during periods of high variable generation.

to consume electricity. Between 10 AM and 3 PM the available PHS capacity is used at its maximum rated capacity of 5.2 GW to store a share of the surplus electricity. At 6 PM the generation of electricity from the combined baseload- and variable capacity decreases below the electricity demand. The marginal cost increases to the level of production costs of CCGT fleets outside Spain at 68 €/MWh due to the functionality of the integrated market. The higher marginal cost grants the normal hydro fleet and PHS fleet, again at maximum rated capacity, the possibility to start producing electricity at a profitable margin.

In the past, centralized storage facilities, that is- facilities mostly oriented on diurnal cycles, focused on night-time consumption when demand and prices were low and daytime discharge when demand and prices were comparably high. The example case shows us that with increased levels of penetration of VRES, in particular solar-PV due to their inherently narrow temporal generation, this approach becomes less viable. That said, the case does show potential for electricity storage in a high variable generation environment for diurnal cycles, yet rather with more dynamic periods of consumption and discharge, mostly depending on the variability in generation and the magnitude of consumer demand at associated timeframes. We will discuss the implications of this observation in section 5. Furthermore, the example also shows that in some cases storage alone is not sufficient for treating all electricity surplus. An additional effect of storing the electricity in this situation is that it prevents congestion on the transmission lines between Spain and its neighboring countries. As a result, the combined market is not affected, securing a balance in marginal cost of electricity generation between the adjacent zones.

At the right side of Figure 4, during the weekend of February 3 and 4, there is a consistent oversupply of electricity due to a longer period of high VRES generation in combination with a lower consumer demand. The PHS facilities in Spain consume electricity during this period at full capacity for almost 30 hours straight. Large part of the consumption occurs at a low marginal cost of 6.4 €/MWh, determined by generated electricity from the nuclear fleet. The electricity is stored for later discharge during periods of higher marginal cost to secure a profitable cycle. This can either be in following days or on a seasonal basis. Not all countries with PHS fleets are suitable for securing long-term electricity storage. For Spain this is feasible due to a large storage capacity within their 2030 power system. For other countries it is less plausible because of a relatively smaller storage capacity. In the case of Germany for example it is below 70 GWh. Their maximum rated capacity on the other hand is significantly larger at 10.9 GW. This makes the PHS fleet in Germany more suitable for diurnal storage cycles, with a maximum of seven hours of electricity storage at full working capacity. This case indicates that PHS fleets in some countries, but not all, have potential for long term consumption of electricity surplus and following storage. The stored electricity can be discharged in a later stage, facilitating renewables penetration and preventing costlier generation. It also shows, like the Italian case in section 4.1, that especially during periods of lower demand such as weekends or national holidays, assets for balancing peaks in variable generation are crucial for an optimally functioning power system.

In figure 5 Spain's storage capacity is used in a different setting. In the methodology of this paper we mentioned that Artelys Crystal Super Grid optimizes its simulations of the European power system within a user-defined sliding time horizon. An important consequence of this approach can be seen during November 24, where additional electricity is being produced by the CCGT fleet after which it is temporarily stored. The stored electricity is then used in a period where variably produced electricity is less dominant, and the marginal cost is higher. November 28 is an example of such a day. The use of the stored electricity from the PHS fleet, next to the hydro storage fleet, prevents that more expensive power plants such as coal or lignite are dispatched throughout most of the day.

A more extensive view on the dynamics of the PHS fleet in Spain during this period can be seen in the lower part of the graph. The set horizon allows the model to make decisions based on cost-efficient optimization, assuming perfect foresight of changes in demand and non-dispatchable generation within this horizon. This results in the Spanish power system producing additional electricity from mainly CCGT almost consecutively for a period of four days, at a marginal cost of around 68 €/MWh. The relatively low marginal cost, compared to later days within the simulation horizon, motions the PHS fleet to consume electricity. The electricity stock in the PHS fleet during this period rises gradually. When generation from VRES decreases and the marginal cost rises, the PHS fleet starts discharging electricity at a profitable margin for again a few consecutive days until the stock is emptied. The reason that this can be

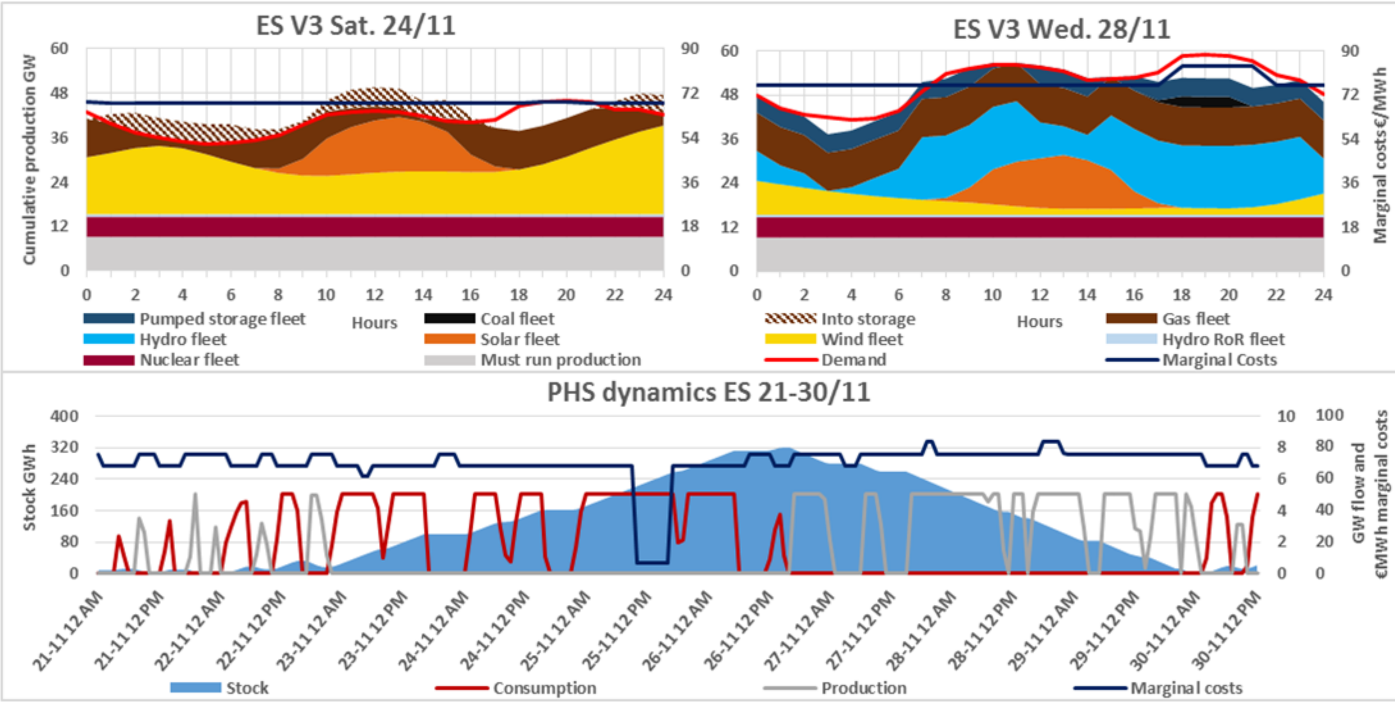

Figure 5 2030 electricity generation and consumption in Spain (ES), November 24 (Top left) and November 28 (Top right) to showcase the potential of thermal based storage in a European power system with high CO2 price. Lower part of the graph shows the dynamics of the PHS fleet in Spain during this period.

profitable, even after conversion losses in the storage cycle, are the large differences between cost of generation per technology because of the high CO2 price in the simulated European power system.

This example indicates that storage can also be very useful for optimization of the electricity generation costs. In practice, a key aspect in this light would be the correct forecasting of load, variable generation and fixed generation availability for longer time frames, to be able to determine with high certainty that storage of fossil generated electricity would be profitable.

4.3 *Utilization of interconnections*

The functionality of centralized storage for domestic purposes has been identified. Although the potential is significant, not all countries have access to large scale electricity storage and even if they do, installed capacities are often limited. Furthermore, considering round trip efficiencies of PHS ranging between 70% and 85% [16], direct utilization of generated electricity can generally be seen as more cost-efficient. This section assesses the functionality of the available interconnection capacity in the 2030 European power system through a range of exemplary cases.

4.3.1 <u>Impact of variable generation on flow dynamics</u>

Figure 6 showcases the flows of electricity from and towards Germany during two deviating days within the simulated 2030 power system. Roughly 63% of Germany's installed capacity in the simulated system is based on VRES. In total during 34.6% (3035 hours) of the year, Germany produces more electricity by its combined capacity of VRES and 'must run' power plants than needed for the domestic demand. At July 17, there's a strong peak production of electricity in Germany and other Northern countries from VRES. This production results in a large oversupply in the entire area at daytime. The effect is that during these hours, Germany imports electricity from the Scandinavian countries and the Netherlands (which imports electricity simultaneously from Scandinavia and Great Britain) and exports electricity towards the south and east. When the evening starts, and the electricity generation from solar-PV decreases, the export stops. The domestic generation drops below the demand at that timeframe and Germany starts importing electricity from Austria combined with a continuous import from the Scandinavian countries (nuclear and hydro).

During February 13 a different situation occurs. It is a cold winter day in Germany, resulting in a high demand for (electric) heating during hours when people are generally at home, in combination with a relatively low input of variably generated electricity. In these hours of high demand, the net import of electricity increases significantly, mainly from baseload or storage-oriented countries, such as Austria, France and Switzerland. During in-between periods of lower demand, the net import decreases and Germany's system adequacy can be fulfilled with mainly domestic peaking plants.

Although there are clear differences visible in these situations and an ongoing change in dynamics, there are also some recurring elements. For example, that an almost continuous load flow exists from Germany towards Poland and the Czech Republic because of relatively low domestic cost-efficient generation capacity within these countries. Furthermore, the Scandinavian countries almost continuously

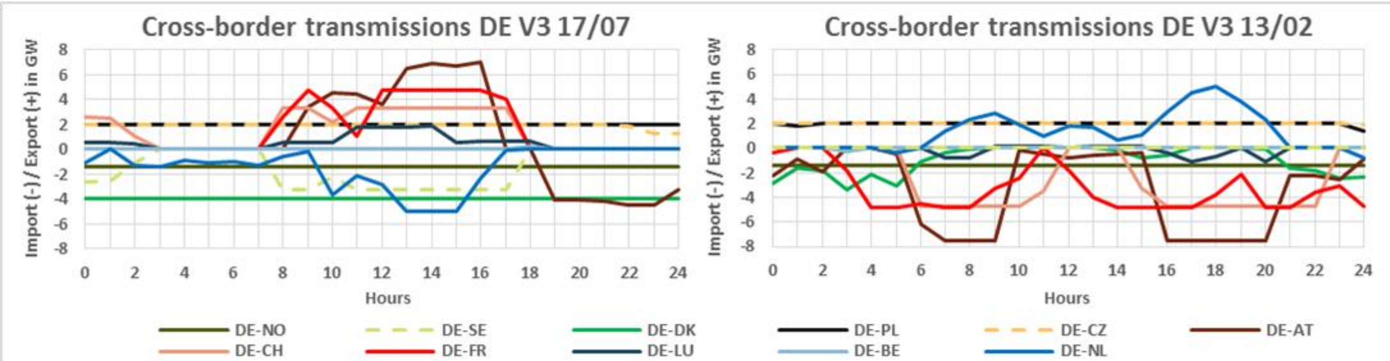

Figure 6 Load flows from and towards Germany during July 17 and February 13. Negative values indicate import, positive values indicate export. Lines of the DE-CZ and DE-SE connections are dashed to show the underlying connections of DE-PL and DE-BE at equal load.

export electricity towards Germany, whereas countries such as Austria, France, Luxembourg and Switzerland with relatively lower influence of VRES predominantly act responsively. These countries generally import during peaks in Germany's generation and export when domestic generation in Germany is low. The Netherlands has a strong resemblance to the German power system and is often influenced by correlated changes in wind speeds and solar irradiation. According to Monforti and colleagues [42], there is a 78% country-to-country correlation in wind power between Germany and the Netherlands. This correlation often results in simultaneous peaks and lows in variable generation. Thus, when Germany has a net export usually the same occurs in the Netherlands, as well as during net import. The Netherlands is also used as a transit country between load centers as Great Britain and Germany.

4.3.2 Dispersing renewable surplus electricity

Denmark has the highest relative fraction of installed capacity of VRES at 66% in the 2030 power system, of which 55% from on- and offshore wind. During in total 4442 hours in the simulated year, Denmark produces more electricity from their VRES capacity alone than needed for domestic demand. Combined with their must run capacity and renewable thermal fleet (biomass combustion), this increases up to 5166 hours. Since Denmark has no domestic storage fleets, it is dependent on its interconnection capacity for balancing the variability in generation and treating the generated surplus. This is visualized in figure 7. The graph shows the demand and generation profiles of Denmark and Germany during April 18, and their mutual dynamics in cross-border flows. Germany in this situation imports a significant part of the generated electricity from Denmark throughout the day for direct use. The import occurs almost consistently at full interconnection capacity of 4 GW. Although Denmark has a total generation surplus of approximately 51 GWh during this day, the maximum surplus per hour is around 3.2 GW. This means that not all imported electricity from Denmark is based on surplus, which can clearly be seen in the graph. It is an indication that Denmark not only exports its own surplus but is also used as a transit country. More specifically, Denmark imports electricity from Great Britain (surplus renewable electricity), Norway and Sweden (hydro power). The generation profile of Germany also indicates that import of electricity from Denmark alone is not sufficient for fulfilling its demand. An additional 121 GWh is imported from other regions throughout the day. While the interconnection capacity between Denmark and Germany is during 15 hours of the day congested, the marginal cost of electricity generation in both countries is still determined through the functionality of the integrated market. This is possible due to uncongested indirect connections between Denmark and Germany, through the Netherlands, Norway and Sweden.

This case shows several important aspects. The use of the imported renewably generated electricity from Denmark prevents the utilization of more expensive backup generators within Germany, stimulates renewables penetration and prevents electricity curtailment. Furthermore, the functioning of a transit country as Denmark stimulates the generation and

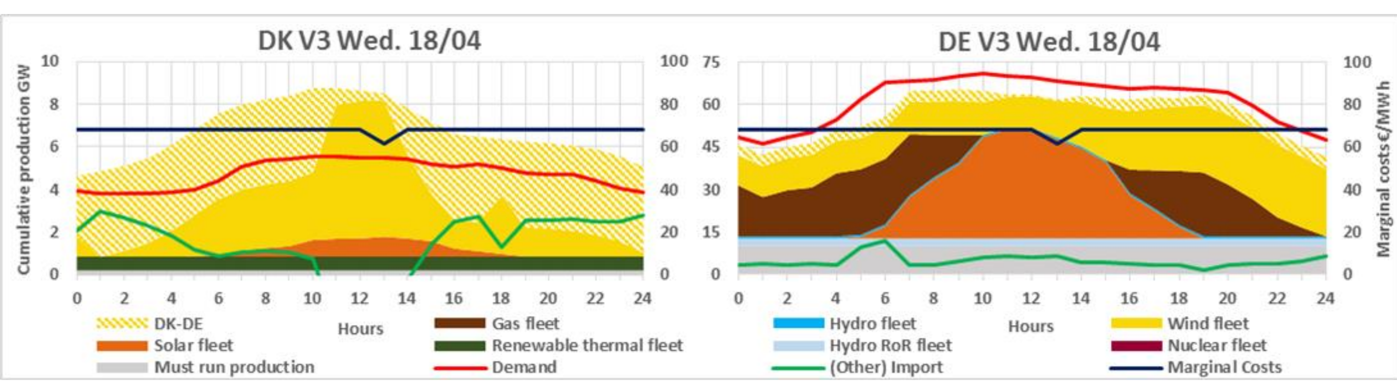

Figure 7 2030 electricity generation and consumption in Denmark (DK) and Germany (DE), April 18**.**

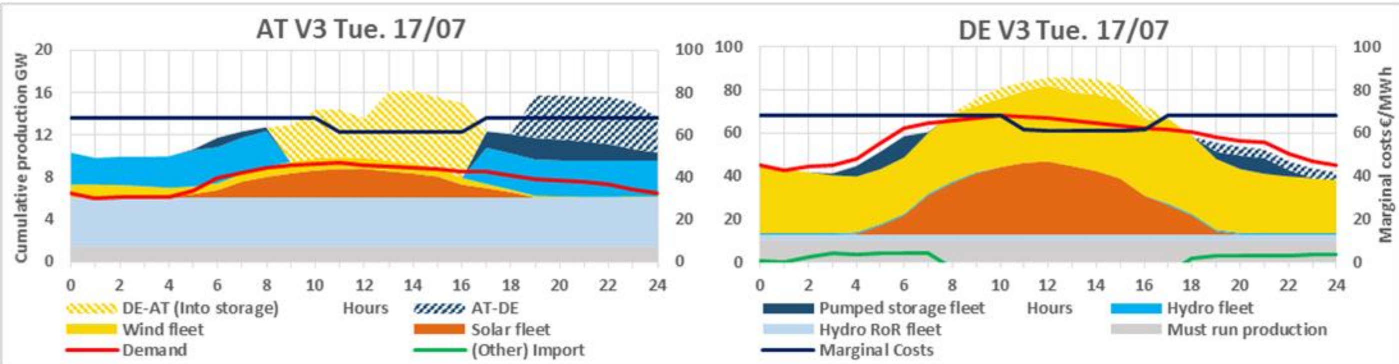

Figure 8 2030 electricity generation and consumption in Austria (AT) and Germany (DE), July 17**.**

flow of cheap renewably produced electricity from different areas towards the load centers in Europe, such as Germany. It also shows the strong impact of countries with high consumer demand and high VRES capacity, such as Germany, during a situation of lower variable generation on the dynamics in the European power system.

4.3.3 Dynamics with foreign PHS fleets

Figure 8 shows the generation within and dynamics between Austria and Germany during July 17, as already touched upon in section 4.3.1. The large oversupply of electricity due to a high variable peak generation in Germany is partly resolved by filling the domestic PHS fleet. This results in a fully stocked storage capacity of just below 70 GWh. Storage alone is not sufficient to effectively use all the generated surplus electricity. Most of the remainder is therefore exported towards Austria below the full transmission capacity of 7.5 GW, totaling 43.2 GWh. Since there is no occurrence of congestion, the functionality of the integrated market between Austria and Germany stays intact. The imported electricity is consumed by Austria's PHS fleet at a marginal cost of 61.3 €/MWh. When the variable generation in Germany decreases below its domestic demand, the electricity flow is being converted from electricity export into import from Austria, almost completely fulfilling the demand in Germany. The remainder comes from electricity generation from Germany's domestic PHS fleet and additional imports from other countries. The imported electricity from Austria is produced by the PHS and hydro fleet, at a marginal cost equal to the production costs of the technology next in line of the merit order, being the CCGT fleet. Besides export to Germany, Austria exports almost 50% of the additionally produced electricity from the PHS- and normal hydro fleet to other regions in Europe (e.g. towards Italy and Hungary) during that day. Indirectly, the cheap surplus electricity from Germany is thus spread out over a larger area beyond Austria.

The general effects and advantages of electricity storage as described earlier in this paper also count for the use of storage in an international context. The current example has shown us the additional benefits of using storage in an international setting through cross-border transmissions of electricity. If a country does not have domestic storage capacity, or alternatively not sufficient, surplus electricity can be exported, stored and imported again in a later stage. This prevents the use of more expensive non-renewable backup capacity for the generation of electricity. Second important benefit is that countries with large PHS storage capacities, such as Austria, Italy, Spain and Switzerland can act as a transit buffer by stocking up on cheaply generated electricity and spreading it at a later stage throughout a wider region.

4.3.4 Preventing loss of load

The case visualized in Figure 9 shows an example where interconnection capacity is used to prevent loss of load (LOL) on the Polish electricity grid. Variable generation in Poland during December 5 is relatively speaking low. Yet more importantly, within the simulated European power system of the TYNDP, the Polish available generation capacity for fulfilling the domestic system adequacy is low as well. These factors

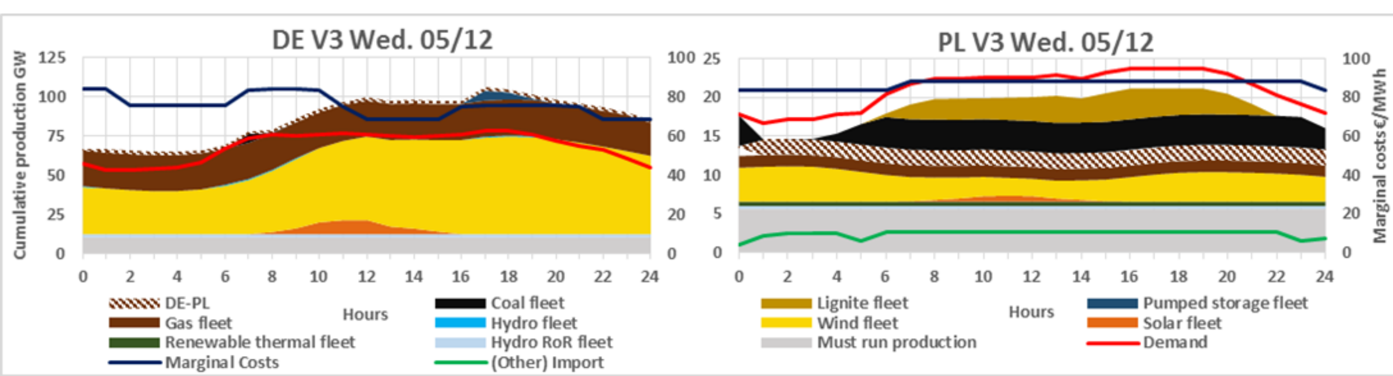

Figure 9 2030 electricity generation and consumption in Germany (DE) and Poland (PL), December 5**.**

combined result in a situation where import of electricity is necessary to prevent LOL and its attached price penalty. Among others, this import is supplied by additional generation of electricity from the CCGT- and coal fleet in Germany. The available transmission capacity between Germany and Poland of 2 GW is fully used throughout most of the day. This affects the functionality of the integrated market, resulting in a separate LMP in Poland at the production costs of the coal fleet and later in the day of the lignite fleet at 88 €/MWh. Although the costs are high, it is a better alternative than LOL on the electricity grid and its consequential economic and social impact.

4.4. *Demand Response (DR) applications*

Despite their potentially significant roles, it has been shown that storage and interconnection capacity are not always available or sufficient in balancing VRES. Shifting the load through DR can potentially decrease the pressure on these assets. In this section, we use the Netherlands as example to assess the impact of DR. The Netherlands has been chosen because it has a relative straightforward system with a high capacity of VRES at 49.5% of total installed capacity and a large fleet of gas power plants at 23.6% of total installed capacity. Changes in the system dynamics are therefore easy to analyse.

During February the 21st, a relatively consistent influence of variable generation appears in the Netherlands, as shown in Figure 10. From 12 AM until 9 AM the generation of electricity from the CCGT fleet is equal in both cases at its full capacity of 4.4 GW. In both cases the generation is also larger than the domestic demand. Additional electricity is being generated due to a larger availability of cost-efficient generation at that time than in nearby countries. Yet, there are also important differences visible between the original and the DR adapted case. With the original load profile, the total export towards Belgium is congested at its full transmission capacity of 2.4 GW, affecting the functionality of the integrated market. Potentially this can be bypassed with indirect connections through Germany or the UK, but in this specific situation these transmission lines are also fully utilized. The LMP in the Netherlands is thus not influenced by more expensive generation in Belgium. In the DR adapted case the export is below the maximum transmission capacity, preventing transmission congestion. The marginal cost of generation in the Netherlands is thus influenced by Belgium's, and possibly beyond, costs of generation. From the viewpoint of solely the Netherlands this higher marginal cost might be unwanted, but the principle of the integrated market is that the overall costs of generation throughout Europe decreases. This means that in some cases, in some countries, the marginal cost can increase while in other cases it decreases compared to separate national market prices. In the end the average marginal cost throughout Europe decreases when transmission congestion can be prevented. From 10 AM onwards, the relatively lower peak demand in the DR adapted case prevents a significant amount of generated electricity from the CCGT fleet, totaling almost 6 GWh on this specific day. The demand can be largely fulfilled by cheaper and cleaner domestic generation, combined with renewable electricity import from the Nordic countries. Thus, this case shows that DR can help decrease system congestion, consequentially lower overall system costs and that it can stimulate renewables integration.

At daytime during August 2 in the Netherlands, as shown in figure 11, there's a temporal peak in variable generation of electricity. For this case, we adapted the load profile based on a load shift from off-peak to peak demand hours during summer time. The relative shift per hour has been determined based on exemplary data of the original load profile of the TYNDP from a comparable day in the summer period. The increase in load during peak demand hours is compensated by equal relative decrease in load during off-peak hours. The total amount of electricity demand remains equal in both cases.

The left side of figure 11 shows the simulation with the original load profile of V4 without any influence of DR. The right side shows the adapted case. The shift creates a situation where a larger fraction of the peak generation can be used directly. The necessary export of generated surplus electricity decreases with more than 8 GWh. Furthermore, because the demand during off-peak hours is significantly lower, the need for generation of electricity from the CCGT fleet and the net electricity import decreases as well. Electricity generated by the gas fleet decreases with almost 5 GWh and electricity import with 3.5 GWh. The marginal cost of generation in this particular case does not change due to the functionality of the integrated market. It is primarily determined by generation of electricity from CCGT fleets outside the Netherlands. This case shows that

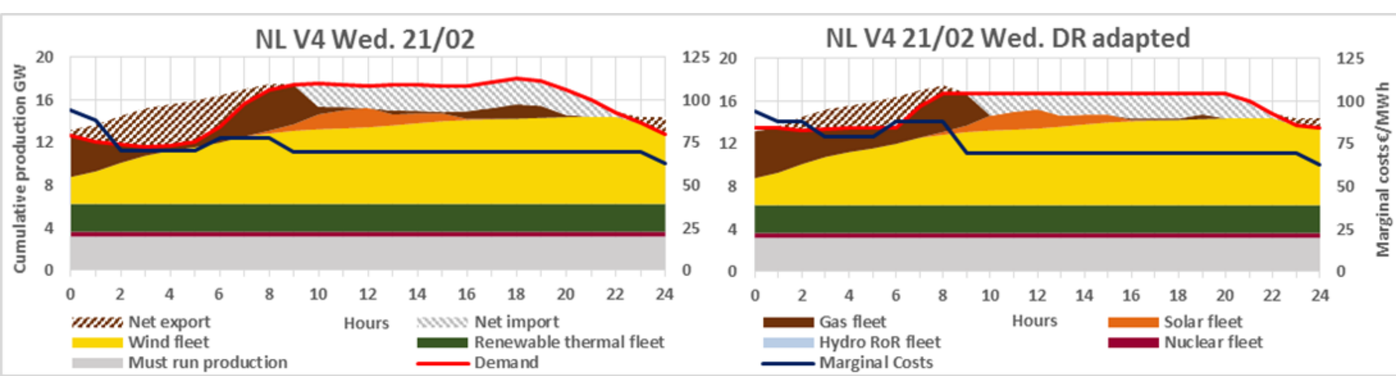

Figure 10 February 21, 2030 electricity generation and consumption in the Netherlands (NL), with on the left the original load profile and on the right the DR adapted load profile.

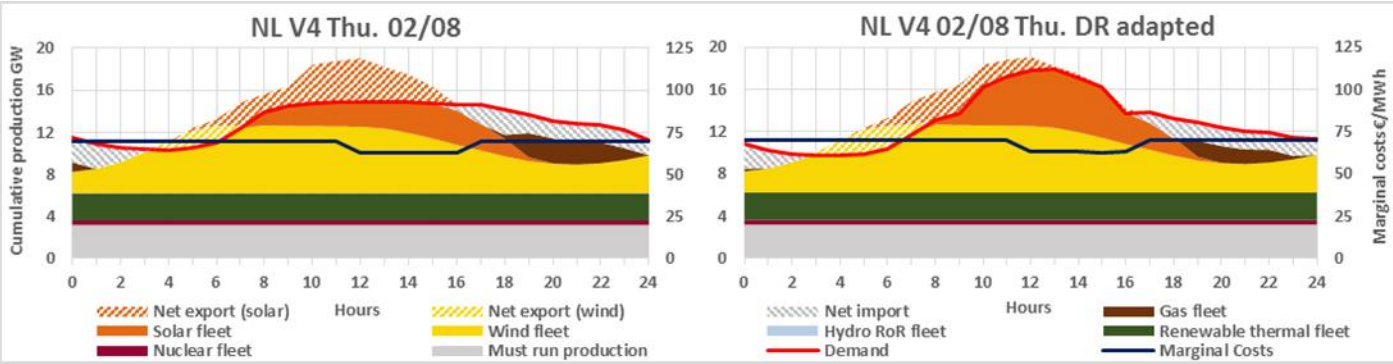

Figure 11 August 2, 2030 electricity generation and consumption in the Netherlands (NL), with on the left the original load profile and on the right the DR adapted load profile.

with higher penetration of VRES it can be rewarding to integrate load shifts following peaks in variable generation.

5. Discussion

As with all studies based on simulation modeling, the results of this study are influenced by simplifications and limitations. Main simplification for this study is that within the simulated European power systems, the use of DR is prioritized due to a pre-integrated effect on the load profiles. It is not an active component of the merit order, so it is applied without any costs attached. In practice this is likely unrealistic since actors capable of realizing a load shift should be stimulated for doing so, as Drysdale and colleagues argued [17]. In a variety of European electricity markets DR is already a commercially integrated asset, including payments for availability and utilization [19]. If DR would be integrated as an active component within the merit order of the electricity market in the modelled European power system, DR must compete with other assets for balancing the generation variability. In turn, this could affect the system dynamics significantly. This aspect lacks in the assessments of this study.

The simulated 2030 European power systems are meant to provide additional insights on the implications of the projected high renewable visions of ENTSO-E's TYNDP. Hence, the assumptions underneath these visions are used as guideline for the modelling, including high CO2 prices of €71-€76 [38]. This can be seen as a deciding factor within the system dynamics. It is the main determinant for the significant differences in production costs per technology within the merit order of the simulated European power system. In turn, these price differences determine among others the load flows within the power system and the profitability of assets for balancing the generation variability. With this in mind, a question could be raised if the system dynamics in a high variable power system would be significantly different in case of a low CO2 price. The answer would likely be yes. The lower CO2 price would limit the price differential in production costs, making it less attractive to transport electricity over longer distances compared to an increasing profitability of domestic utilization of power plants further down the merit order. Consequentially, the exchange of cost-efficient generation between member states would be restricted. Furthermore, the high CO2 price causes a shift in the merit order between CCGT- and coal fleets which deviates from the current market situation. Nonetheless, following the storylines of the ENTSO-E regarding the development of the different visions [38], it is deemed to be unrealistic to assume that the same capacities of VRES of V3 and V4, as shown in [37], can be reached by 2030 with a lower CO2 price.

The example cases in this study regarding the functionality of centralized electricity storage indicated that the historically common approach of cheap electricity consumption during night-time and profitable discharge during daytime becomes less viable with increased penetration levels of VRES. Especially the increase in generation from solar-PV systems causes a recurring peak in electricity generation during midday, lowering the marginal cost during these hours significantly. An immediate effect of this development can already be seen in Austria, Germany and Switzerland, where the construction of new PHS plants are undermined due to mainly the increase of subsidized solar-PV capacity in Germany [43]. The future profitability of centralized storage facilities focused on diurnal cycles will likely depend on a shift towards a more dynamic approach on consumption and discharge, partly towards daytime consumption, and on other factors such as the development of the CO2 price. High CO2 prices can increase the profitability of storage due to larger differences between production costs per technology as has been shown in this study. Yet, it is also important to consider that these implications are less relevant for facilities able to thrive on seasonal storage.

Furthermore, the high renewable visions of the TYNDP incorporate significant expansion of interconnection capacities by 2030 which affect the dispatch of storage facilities. Whether the net result of this aspect from the viewpoint of centralized storage facilities is negative, electricity can be utilized directly more often which limits the need for storage, or positive, storage facilities can access a larger market, can't be answered based on the results of this study due to the set scope of daily timeframes.

6. Conclusions

This report underlines the significance of assets for balancing generation variability in a potential 2030 European power system in a high variable context. The different 2030

European power systems are assessed in an hourly dispatch model to integrate realistic decision-making functionalities. An integrated market approach is applied based on a zonal pricing methodology. By zooming in on daily snapshots of electricity generation, load, marginal cost and balancing assets, this study creates a better understanding of the dynamics in these high variable systems during deviating situations throughout the year, throughout Europe. The results of this study can be assessed as additional insights on the projections of the ENTSO-E regarding the 2030 European power system, as put forward within their Ten-Year Network Development Plan (TYNDP) [25]. It is shown that there are multiple reasons why assets for balancing variability should be integrated in a high variable European power system. For example, to prevent expensive alternative generation for fulfilling the system adequacy, to manage peak- or consistent oversupply of electricity, especially during periods of lower demand such as weekends or national holidays, or to prevent loss of load on the electricity grid. It is also shown that different cases, such as situations of peak- or more consistent oversupply, require different approaches in providing flexibility. The implementation of centralized electricity storage, increased cross-border transmission capacity and demand response (DR) applications in a high variable electricity generation context, all contribute to the integration of renewables and to optimizing the costs of electricity generation throughout the fully-integrated European power system. More specific findings per asset type in the dynamics between load, generation and marginal cost are:

Interconnection capacity

- Electricity transmission is crucial for treating and dispersing generated (variable renewable) electricity surplus.
- Increased transmission capacity stimulates the use of cost-efficient generation technologies throughout the European power system, by allowing a high and efficient load flow between regions.
- The high CO2 price, and consequential large differences in production costs between technologies in the merit order, allows these load flows to be cost-efficient, even in consideration of the significant transmission losses and wheeling charges.
- Main load flows in the European power system are determined by large load centers based on high capacities of VRES. Examples are Germany, Great Britain and Spain. The impact of these countries on the European power system during periods of over- or undersupply is high.
- Central transit countries with high transmission capacities, such as Austria, Denmark and the Netherlands, are crucial for connecting the load centers with other regions in Europe with different characteristics. For example, to connect them with countries with larger storage capacities or with countries based on a stronger baseload generation.
- Even with the increased interconnection capacities, congestion on the grid can still occur during periods of high or low variable generation, or on connections towards countries with low domestic cost-efficient generation capacity.

Centralized electricity storage

- During occurrence of surplus in generation, electricity storage can prevent system congestion.
- When system congestion does occur, either on the transmission lines or due to an already fulfilled system demand which happens occasionally, the large capacities of electricity storage in the European power system are significant for preventing renewable electricity curtailment.
- The high CO2 price, and consequential large differences in production costs between technologies in the merit order, allows storage of relatively cheap thermally generated electricity to be cost-efficient.
- Countries with large storage capacities can act as a transit buffer for storing and supplying cheaply generated electricity over a longer time span through a larger region.
- The historically common approach of centralized electricity storage fleets focused on diurnal cycles, in the form of cheap electricity consumption during night-time and profitable discharge during daytime, becomes less viable with increased penetration levels of VRES. Future profitability for these facilities requires a more dynamic approach in consumption and discharge cycles.
- Energy to power ratios of storage facilities are highly significant for determination of the optimal utilization (diurnal or seasonal) within a high variable power system.

Demand response applications

- Shifted load through demand response can stabilize transmission dynamics.
- It can prevent system congestion by decreasing the pressure on the capacity of transmission lines or storage facilities.
- It can prevent the use of expensive backup generators, which are in the case of a high CO2 price also the more polluting technologies such as coal- and lignite fleets.
- During days with low variable generation or stable variable generation throughout the day, a load shift from peak to off-peak demand hours can be efficient.
- During days with strong peaks in variable generation during midday, generally in spring or summer, a load shift away from peak demand hours is not always advisable or can even be counter effective. A shift from off-peak demand hours to peak hours in generation can become significant in a high variable power system.
- In any case, potential load shifting through DR should follow the availability of cost-efficient generation.

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